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REVIEW OF WHOLESALE ELECTRIC MARKET DESIGN	**§ §**	**PUBLIC UTILITY COMMISSION OF TEXAS**

<u>TEXAS INDUSTRIAL ENERGY CONSUMERS' COMMENTS</u>

Texas Industrial Energy Consumers' (TIEC's) responses to the Commission's questions are below. Due to length and time limits, TIEC has chosen to focus on certain issues and has not answered every single question. If the Commission chooses to move forward with an administratively determined forward capacity construct, such as the LSE obligation, extensive deliberation will be needed to develop the details around the obligations, performance requirements, accreditation, market power protections, penalties, and other features. TIEC is not in a position to provide complete responses on all of those issues today.

<u>General Market Design Questions</u>

1. The ORDC is currently a "blended curve" based on prior Commission action. Should the ORDC be separated into separate seasonal curves again? How would this change affect operational and financial outcomes?

The current "blended curve" does not appropriately value reserves based on seasonal variability. Overall, the blended curve has increased costs to customers by ***overvaluing*** reserves during the summer peak, when the ORDC is most often triggered, while ***undervaluing*** reserves during non-summer periods. Because these off-peak periods that have caused most reliability issues in recent years, it is imperative to appropriately value reserves during these periods. TIEC anticipates some generators will oppose this change claiming that it "takes money out of the market." However, the Commission's goal should not be to just increase overall prices, but to create accurate, effective market incentives to provide reliable reserves when they are needed most.

The ORDC values reserves based on the probability that, in the next hour, reserves will drop below the Minimum Contingency Level (MCL). In periods where reserves are more variable—such as shoulder months and other periods where the grid is relying more heavily on intermittent generation—the ORDC should set a ***higher value*** for reserves based on the increased operational risk. These periods have become more critical to reliability in recent years compared to peak summer conditions. Indeed, reserve variability has been lowest during summer months, where ample dispatchable generators self-commit to be available for peak hours. A "blended" curve assumes the same level of reserve variability throughout the year, which is obviously incorrect. Managing shoulder periods with low-to-medium load and high levels of intermittent generation output has become an increasing reliability concern. Under-valuing reserves during these periods fails to provide appropriate price signals for dispatchable reserves to provide reliability under these conditions, and should be corrected.

The original formulation of the ORDC had twenty-four total curves. TIEC does not necessarily think this number of curves is necessary, but eight curves (two per season, for on-peak and off-peak) would provide more accurate valuations of reserves and reflect actual system variability. This will provide more efficient pricing for consumers, and it will also improve financial incentives for dispatchable generation to be available in ***all*** seasons, not just the summer.

2. What modifications could be made to existing ancillary services to better reflect seasonal variability?

The existing ancillary services suite has historically been used to address (a) hour-to-hour variability and (b) certain potential contingencies. Except for Non-Spinning Reserve Service (NSRS), which is designed to manage hourly variability in net load (i.e., variability in demand and intermittent generation output), the existing ancillary services were primarily driven by NERC requirements. The volumes procured varied by season, but the focus was still hour-to-hour variability and NERC contingency requirements.

Recently, ERCOT has begun using NSRS and RRS to cover off a greater range of potential reliability issues, such as variability in intermittent generation relative to ***seasonal averages*** (rather than just hour-to-hour), higher-than-expect forced outages, and unusually high demand throughout a season. This expansion of ancillary services has reduced reliability issues related to ramping issues and unit commitment. However, the quantities are not based on any historical evaluation of actual variability, but a "best guess" of what would cover the potential risks. TIEC supports a more disciplined evaluation of actual, seasonal variability for these reliability factors (intermittent output, forced outages, demand) to better inform the additional procurements. The procurements should also be adjusted throughout the day based on historical variability, rather than a fixed quantity regardless of whether it's late afternoon or the middle of the night.

While repurposing existing ancillary services is appropriate as an interim measure, many operational conditions do not necessarily require resources with the response times required for

NSRS and RRS. Ultimately, TIEC believes a product similar to the IMM's "Uncertainty Product," combined with the planned ERCOT Contingency Reserve Service (ECRS), would be a more appropriate way to cover off these risks than buying additional high-quality products like NSRS and RRS. TIEC has proposed a similar product in prior comments, targeted specifically at the uncertainty around the load carrying capability of intermittent generation. Such a service should ultimately provide a lower-cost and potentially more effective solution.

3. Should ERCOT develop a discrete fuel-specific reliability product for winter? If so, please describe the attributes of such a product, including procurement and verification processes.

a. How long would it take to develop such a product?

b. Could a similar fuel-based capability be captured by modifying existing ancillary services in the ERCOT market?

TIEC has consistently supported a fuel security product to address extreme winter conditions, as envisioned by Section 18 of SB 3. Competitive markets have a difficult time rationalizing high cost but low probability outcomes like February 2011 and Winter Storm Uri, which can result in insufficient market-driven fuel security. For example, most generators will contract for firm gas (or storage) sufficient to meet their expected winter capacity factors, and they reasonably plan to rely on the spot market for additional interruptible purchases. Most of the time, this is a reasonable and economically efficient way to procure fuel. However, during rare, extreme winter conditions like last February, this approach may result in inadequate fuel supplies.

TIEC believes that a separate, competitively bid product similar to Black Start Service would be the simplest approach to address this issue and it should not take long to implement (as it would not impact the Energy Management Systems (EMS) or impact existing ancillary service procurement practices). The Commission would need to set the appropriate quantities and determine which fuel security measures are eligible. Critically, these measures should exceed the level of fuel security generally maintained in the market. Dual fuel capability, secure on-site storage, and similar "above-and-beyond" measures should be the objective. TIEC envisions that resources participating in the service would be able to freely participate in the market and provide energy or ancillary services as they choose. The service would create additional fuel security for these market resources, which would allow them to perform in situations where normal fuel supplies are disrupted to justify the payments. Requiring a subset of existing or future ancillary services to meet heightened fuel security requirements would also work as a longer-term solution, but would take longer to implement and would be more complex to administer.

4. ***Are there alternatives to a load serving entity (LSE) Obligation that could be used to impose a firming requirement on all generation resources in ERCOT?***

An LSE obligation does not inherently create any "firming" requirement. An LSE obligation is a mandate to make load-serving entities, and ultimately customers, pay for an administratively-determined total quantity of installed generation, based on assigned capacity values for each technology. Under an LSE obligation (or any similar forward capacity construct), customers are not forced to buy a certain quantity of any ***specific resource type***, just a total quantity of capacity based on the assigned capacity values. Assigning a low capacity value to intermittent generation will not materially change the overall resource mix, which is being driven by federal subsidies and ESG investing. Since intermittent resources likely do not need any additional value from capacity credits to support their development, forward capacity obligations are unlikely to reduce investment in intermittent generation or increase dispatchable generation. In fact, if intermittent resources are already the cheapest to develop (for the reasons noted above), any extra LSE obligation payments may only make them more appealing. Likewise, a potential penalty for non-performance during key intervals will just be priced in for intermittent resources based on the size of the penalty, and the probability they will be below the assigned capacity value during the measurement periods over time. Depending on these inputs, the performance penalty is unlikely to materially change the pricing advantage of buying solar or wind. For these and other reasons, TIEC does not believe that an LSE obligation inherently firms the generation mix. Rather, it creates a complex, bureaucratic obligation for customers to fund a specific quantity of installed total capacity (with various administratively determined capacity accreditation values and corresponding penalties that may have little to no impact on actual reliability) and creates a mandated revenue stream for existing thermal generation. This approach has not been effective to address intermittency in other jurisdictions, and TIEC does not expect a different outcome here.

As alternatives, TIEC sees two potential options for market-based firming incentives that are complementary to the current market design and do not involve a forward capacity mandate:

i. Ancillary Service Allocation Based on Variability.

First, the Commission could allocate existing and/or future ancillary services that are meant to address the operational issues around seasonal variations in intermittent generation, forced outages, customer demand, and similar factors based on cost causation. This could apply to ECRS, a certain quantity of NSRS, or new products like the IMM's proposed "uncertainty product" that are designed to meet seasonal variability issues—which TIEC believes is the actual reliability problem facing ERCOT. Allocating services meant to ***protect*** against these potential reliability events based on cost-causation—even if the events do not occur—will create additional financial incentives for resources to "firm up" and for LSEs to appropriately hedge. This will provide additional revenues for dispatchable generators, create additional firming incentives for intermittent generators and load-serving entities, and enhance the existing financial penalties for forced outages without a heavy-handed capacity construct. TIEC has suggested using a modified Reliability Unit Commitment (RUC) allocation to capacity-short QSEs as a potential approach, but is open to other approaches that are non-discriminatory and based on dynamic cost-causation that encourages real-time market response. This solution will maintain current performance incentives and allow the market to continue to solve for these issues when they are sufficiently predictable, but will provide enhanced hedging and performance incentives even when there are no actual reliability events.

ii. Dynamic "Failure to Firm" Penalties for All Resources.

If the Commission seeks to directly penalize unpredictable and unreliable performance during net peak load conditions without harming customers, it could also create a seasonal firming requirement where generation availability during net peak load events is measured relative to expected seasonal performance expectations. TIEC believes this approach would have similar outcomes to an ancillary service assignment, but a penalty-based system would not necessarily involve identifying which ancillary services to assign or conducting a detailed and likely contentious cost-causation analysis.

Under this approach, generator performance would be measured during certain critical periods (this could be an interval, hour, or multiple hours), and generators who do not meet the performance expectations would pay a penalty based on their shortfall. The penalty could potentially be based on the ORDC, similar to the IMM's proposal, which would naturally increase during the most critical system conditions. The penalty would apply to any generation that fails to meet seasonal availability expectations during critical periods, including ***both*** intermittent generation and dispatchable generation that fails to perform relative to expectations. Determining which period during a given season is the highest "net peak load" interval or hour to measure performance for penalties would require a look-back at the end of the season, similar to a 4CP allocation. This would make contemporaneous assignment of the penalties impossible. To overcome this issue, the penalties could instead be automatically triggered anytime reserves fall below a certain level as a proxy for net peak load conditions. The penalty payments could be credited back on a load ratio share during the critical periods to offset ancillary service costs and high energy prices for customers and LSEs caused by the unpredictable performance. This would incentivize firming without creating additional costs for customers, unlike capacity obligations or similar constructs, as an enhancement to the existing market design.

5. Are there alternatives to an LSE Obligation that could address the concerns raised about the stakeholder proposals submitted to the Commission?

TIEC continues to believe that providing additional revenues for dispatchable generation through new or expanded ancillary services that target seasonal variability is the most cost-effective solution to the ***actual*** reliability issues ERCOT faces. Proposals that require customers to fund a certain level of total installed capacity, whether framed as an LSE obligation or a generalized "backstop" capacity procurement, are necessarily based on administrative determinations about future conditions, how generation resources will perform in real time, expected demand, and other inputs that will almost certainly be wrong. Under our current market design, customers only pay for resources that perform. Under any form of installed capacity construct, customers will be forced to pay for resources in advance and then ***hope*** they perform. This shifts substantial risk to customers and is a step backward toward regulated rates and integrated resource planning. No administrative penalties can actually ensure performance. This was demonstrated during Winter Storm Uri, when massive financial losses were inadequate to ensure that existing generators delivered when needed most. Rather, the risk of after-the-fact penalties will just be priced into the capacity offers. The overall result will be to shift substantial risk from competitive generators to customers and increase total market costs without meaningfully improving reliability.

With respect to the various "backstop" proposals specifically, TIEC also understands that a primary objective of the market redesign is to make additional reliable reserves available ***in the market before emergency conditions***. The majority of the "backstop" proposals would hold capacity out until an emergency and then set prices for customers as if the capacity does not exist. This fails to solve the underlying problem and forces customers to purchase capacity without getting any energy price benefits of those purchases. At this time, TIEC does not see a way to fix these fundamental issues.

<u>Load Serving Entity (LSE) Obligation</u>

6. How can an LSE Obligation be designed to protect against the abuse of market power in the wholesale and retail markets?

- ***a. Will an LSE Obligation negatively impact customer choice for consumers in the competitive retail electric market in ERCOT? Can protective measures be put in place to avoid a negative impact on customer choice? If so, please specify what measures.***
- ***b. How can market power be effectively monitored in a market where owners of power generation also own REPs that serve a large portion of ERCOT's retail customers?***

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- ***e. Can market power be monitored in the bilateral market if an LSE Obligation is implemented in ERCOT? Can protective measures be put in place to ensure that market power is effectively monitored in ERCOT with an LSE Obligation? If so, please specify what measures.***
- ***f. Should the LSE Obligation include a "must offer" provision? If so, how should it be structured?***

A truly decentralized LSE obligation will inevitably favor large, incumbent "gen-tailers," meaning REPs that are affiliated with legacy generation owners. Under a physical LSE obligation, these "gen-tailers" have an inalienable, built-in competitive advantage because they already own physical capacity to hedge some or all of their load. Pure-play REPs, by comparison, will have to attempt to purchase capacity from third parties—including their gen-tailer competitors. This places all other competitive retailers at an immediate and substantial disadvantage. For this reason, a decentralized LSE obligation will almost certainly create additional barriers to entry for pure-play REPs and spur further retail consolidation. Similarly, the credit and financial requirements it would impose for competitive REPs to procure capacity three years in advance—without any guarantee that they will have a retail book sufficient to support that obligation—make this type of proposal essentially unworkable except for the large incumbent gen-tailers. This was one of the main reasons the Commission previously rejected an LSE obligation in the 2013-2014 timeframe. As large sophisticated customers who, in some instances, have their own affiliated REPs, TIEC members may be better suited than smaller customers to navigate these issues. However, for the retail market at large, TIEC questions whether a model that forces retail and generation consolidation and creates heavy barriers to entry for pure-play REPs offers any real advantage over regulation. With such a consolidation of market power, customers may be better off with the opportunity to comprehensively review their providers' rates under a regulated regime.

The benefit of an LSE obligation over a centralized forward capacity market is that capacity would be paid based on bilateral contracts (*i.e.*, paid "as bid") rather than a centrally procured marginal clearing price. A centralized clearing model is the worst outcome for consumers, as customers would pay a clearing price for both energy and capacity.[1] However, the downside of a decentralized LSE obligation is that there is no way to effectively force a level playing field for all LSEs. Any type of "must offer" approach, or somehow requiring all capacity to be offered to all LSEs on an equal basis, will almost certainly translate to central procurement and clearing. TIEC does not believe that a bulletin-board posting system will be sufficient to address these issues, as this still does not ensure that gen-tailers will offer their capacity to third parties at competitive prices. Instead, additional regulatory requirements would be needed, such as some kind of must-offer, intense market monitoring, and likely central clearing, which would ultimately start to look a great deal like a centralized forward capacity market. For these reasons, TIEC is extremely concerned that attempting to address transparency and market power issues in an LSE obligation would ultimately translate into a central clearing model with even greater downsides.

c. What is the impact on self-supplying large industrial consumers who will have to comply with the LSE Obligation and will it impact their decision to site in Texas?

Since deregulation, Texas has held a huge economic development advantage by maintaining the only truly competitive electricity market in the world. Texas offers a unique opportunity for large businesses to tailor their electric supply to their individual risk tolerances and

[1] Today, customers pay a clearing price for energy and ancillary services, but they are not forced to make fixed payments to generators for their capacity. In a regulated model, customers pay for capacity but they get the energy at cost, plus a share of profits from wholesale sales. A capacity market requires customers to pay a clearing price for capacity ***but*** they never own the plants and also buy the energy at a clearing price.

reliability needs in a dynamic and flexible way. During the nearly two decades of ERCOT's energy-only market, Texas has seen one of the greatest expansions of its economy, and the ERCOT market has often been cited as a key reason for companies locating facilities in Texas. As compared to FERC-jurisdictional markets, Texas has avoided the inefficient costs and administrative bloat of capacity mandates. By their nature, forward capacity mandates—including an LSE obligation—are manufactured "markets" driven by static, government-dictated measurements of "reliability" that are highly contentious and almost always inaccurate. Today, generators are paid when they provide services to customers and actually perform. Under forward capacity constructs, generators are paid a fixed revenue stream in advanced and penalized if they ***do not*** perform—penalties that end up being bid into the capacity price. This shifts considerable risk and cost from the generators to their customers and substantially reduces the amount of generator revenues that are truly tied to performance, which may ultimately harm reliability.

For large industrial customers, reliability and cost are equally important. TIEC recognizes the need to ensure that our current market design appropriately incentivizes investment in reliable generation. However, TIEC urges the Commission to pursue changes that will actually improve customers' reliability, rather than enriching incumbent wholesale market participants and shifting risk to customers. The introduction of a capacity construct in Texas—including a decentralized LSE obligation—will erode the competitive energy advantage Texas's flexible, competitive model has historically offered. Rather than allowing large customers to dynamically manage their risk and secure supply based on evolving needs and risk tolerances, an LSE obligation will force customers into an inflexible three-year forward procurement based on a static set of administrative assumptions. This is why TIEC prefers approaches to incentivizing reliable, dispatchable generation that are consistent with our current market design—including targeted reliability and ancillary services, with appropriate allocation based on cost-causation. While these are real-time or day-ahead solutions, if they are transparent and predictable to the market they will provide long-term investment incentives without the need for a three-year forward mandate.

From a practical standpoint, an LSE obligation is very challenging for a customer seeking to site in Texas. Customer migration of residential and small commercial customers among LSEs is granular, which at least facilitates a "range" of outcomes for a future period based on historical trends. Indeed, the vast majority of LSEs already hedge their load forward based on their best guess of their future retail load—recognizing that they are able to easily supplement or trade out of energy hedges closer to real-time as needed. A new large customer presents an entirely different set of issues. First, it is unlikely that a new large customer will (a) have certainty as to their maximum demand three years in advance, and be in a position to (b) select an LSE and give them sufficient time to find a physical hedge for a large quantity of load three years in advance. In reality, this means a customer seeking to site in Texas will somehow need to find an LSE that already has sufficient "length" in its capacity position to accommodate the customer's load within the three-year forward period. Particularly in a decentralized LSE obligation, it could be difficult if not impossible to find an LSE that is willing to take on the additional cost and risk of serving a large customer. This could result in very costly capacity obligations for a large customer if they do not have certainty three years in advance as to what their load would be and which LSE they want to use, such that a forward capacity hedge can be procured at a reasonable price. TIEC does not believe that tradeable "capacity credits" will fix this issue, as a large industrial customer would still be a "late-comer" to the hedging mandate and this will inevitably come at a price premium. A regulated model with more predictable rates may even be more attractive than the unknown additional capacity cost created by this type of decentralized LSE obligation for a new facility.

Aside from siting new facilities, an LSE obligation will limit large customers' ability to dynamically manage their costs by actively participating in the market. The E3 proposal includes a way for large customers to essentially "self-provide" capacity by being interruptible. However, TIEC does not believe this is likely to be effective in practice for a number of reasons. First, many large manufacturers are not interruptible at all due to the nature of their processes, and will be fully exposed to a three-year forward mandate. Second, even those customers who ***are*** interruptible typically cannot guarantee a particular level of interruptibility three years in advance. Factors such as the market price of the product they manufacture, the status of production quotas to meet their own supply contracts, and other external factors cause interruptibility to be a very dynamic calculation. Today, if a customer has bought an energy hedge and it is no longer needed, it can liquidate that position in the DAM or real-time markets. Because the LSE capacity credits will not be centrally procured or cleared through ERCOT, it is unlikely that the same flexibility will be available for large customers to dynamically manage their positions. This has been one of the biggest selling points for the ERCOT market for large businesses and TIEC urges the Commission to be very deliberate in moving away from this model toward a forward capacity mandate.

8. Can the reliability needs of the system be effectively determined with an LSE Obligation? How should objective standards around the value of the reliability-providing assets be set on an on-going basis?

a. Are there methods of accreditation that can be implemented less administrative burden or need for oversight, while still allowing for all resources to be properly accredited?

b. How can winter weather standards be integrated into the accreditation system?

Administrative determinations of reliability needs and resource values are inherently flawed and inaccurate. As an example of this, academic modeling has predicted that Texas would have resource-adequacy driven power outages at various times since deregulation began. These predictions have ranged from once in ten years to once in two years, based on static (and flawed) estimates of reserve margins for peak demand conditions. However, ERCOT has ***never*** experienced firm load shed during a peak demand period because the system "ran out of capacity." This is, in large part, because static, assumption-based modeling cannot accurately predict market response—particularly from distributed resources and demand response. Similarly, during the prolonged debate over market design from 2011-2014, the Commission ultimately decided to retain the current design with the addition of the ORDC after finding that ERCOT's load forecasts were materially overstating future load growth. Once the load forecasts were revised, the reserve margins looked healthy ***even though nothing had actually changed***. Again, this demonstrates the hazard of mandating fixed revenue streams around inherently flawed administrative assumptions.

For the past twenty years, Texas has had comparable or superior reliability to other markets with a lower overall cost to customers. The reliability issues ERCOT has experienced have all been driven by ***operational issues***—such as unpredictable extreme winter weather and variability in generation output due to intermittent resource and forced outages. A forward capacity obligation or other steps back toward centralized resource planning almost certainly would not have impacted these outcomes. In fact, by reducing the amount of generator revenues that are tied to performance, it might have even made them worse. This is why TIEC continues to believe that focusing on real-time market incentives is the best approach.

10. How will an LSE Obligation incent investment in existing and new dispatchable generation?

Whether an LSE Obligation will meaningfully impact current investment trends largely depends on the nature of the forward mandate, the accreditation process, and the performance penalties. Importantly, however, intermittent technologies do not need additional revenue streams to justify their construction today, and there is no realistic framework for an LSE obligation where these resources receive zero capacity value. As a result, these resources will continue to be built, and may even accelerate under such a construct. Federal policies, ESG investing, and overall economic advantages mean that intermittent generation will continue to be favored. It may very well be more cost-effective to procure renewable generation sufficient to meet an LSE obligation even at a lower capacity factor than to try to fund new dispatchable generation that will inevitably operate at a low capacity factor and require the majority of its revenues to be made through a forward mandate. This is, in large part, what has been observed in other jurisdictions with forward capacity obligations. For this reason, it is possible that an LSE obligation will increase costs for customers and provide a false sense of security, but without improving customers' actual experience of reliability. TIEC continues to believe that supplementing market incentives with additional ancillary service procurements, reserve payments to dispatchable resources, and appropriate cost allocation will foster the right amount of dispatchability (including distributed generation and demand response) without the need for an LSE obligation.

11. How will an LSE Obligation help ERCOT ensure operational reliability in the real-time market. (e.g., during cold weather events or periods of time with higher than expected electricity demand and/or lower than expected generation output of all types)?

An LSE obligation is designed to mandate customer payments to support a certain level of installed generation. TIEC does not believe it will meaningfully improve operational reliability. In fact, if resources rely predominantly on forward capacity payments rather than revenues earned in the energy market, it is likely that operational reliability will actually suffer.

Further, LSE obligations are inherently based on static "snapshots" of future conditions that are inherently unreliable and will not cover all actual scenarios. An LSE obligation imposed in 2018 would not have made any difference whatsoever during Winter Storm Uri in 2021, as the operational issues had nothing to do with total installed capacity or insufficient hedging. By any reasonable metric, an LSE obligation would have shown sufficient capacity to serve load on a total system basis. For this reason, LSE obligations and other forward constructs do not meaningfully protect against outlier weather events or other unpredictable grid conditions. Rather, weatherization requirements, additional fuel security incentives, and similar performance-based measures will have the greatest impact on improving operational outcomes during weather events.

13. What is the estimated market and consumer cost impact if an LSE obligation is implemented in ERCOT? Describe the methodology used to reach the dollar amount.

This is nearly impossible to predict, particularly without more certainty on many details that have not been decided. It may also be nearly impossible to predict for a decentralized "paid-as-bid" LSE obligation with potential market power issues and transparency challenges. However, there are two different impacts that need to be evaluated: wholesale power costs, and retail costs.

Wholesale Costs. Directionally, if the cost of capacity is expected to approach the cost of new entry (CONE) less energy market revenues on a per-MWH basis, then TIEC believes $15-20/MWh is a reasonable estimated capacity cost. Notably, this will climb more renewables are added to the system because the capacity factor for gas turbines (and hence, energy market revenues) will trend lower. For example, assuming a $95 per kW-year cost for a new gas combustion turbine (CT)[2] with a 60% capacity factor,[3] the supplemental capacity cost needed to justify new entry under an LSE obligation would be roughly $18/MWh. However, as additional renewable generation enters the market and capacity factors for CTs trend lower, the necessary capacity payments will increase. For example, at a 40% capacity factor for a CT at a $95 per kW-year capacity cost, the additional cost would be roughly $27/MWh. For a 100 MW industrial customer, a $15/MWH cost increase translates to an additional $13 million in costs per year; a $27/MWh cost would translate to $23.6 million in additional costs per year.

Of course, there are many unknowns that make this type of calculation inherently uncertain, including the role of any additional ancillary service revenues that may not be factored into a capacity factor analysis for the energy market. However, it is important to note that any analysis of what customers will pay "over time under market equilibrium" is not a meaningful evaluation of the additional costs of a capacity construct. The real-time market will still need to send price signals during operational events to incentivize market response, and the frequency and duration of these types of events has proven to not correlate with the level of installed capacity. Further, in a year where the market is not "at equilibrium," including for example if there were unexpected coal retirements or other developments that impacted available capacity, both the costs

[2] This is in the middle of the $70-$117 per kW-year range provided by the IMM. *See* Potomac Economics, 2020 State of the Market Report at 73 (https://www.potomaceconomics.com/wp-content/uploads/2021/06/2020-ERCOT-State-of-the-Market-Report.pdf).

[3] Meaning it is "in the money" and economic to run 60% of the time based on real-time energy prices.

of the LSE obligation ***and*** the real-time market prices could be much higher than predicted by some long-term equilibrium evaluation. TIEC has seen this type of "average equilibrium" cost analysis in the past that predicts all market designs will ultimately require the same cost to achieve the same level of reliability. This completely undermines the core assumptions underlying the efficiency and cost savings of true competitive markets. It also assumes everyone has perfect information and everything works perfectly, which is never the case. Analysis indicating that a forward capacity market ultimately costs the same as a predominantly energy only market has been disproven by reality, regardless of what theoretical models may purport to show. Further, the flexibility of a market without an administrative capacity construct allows customers to achieve a range of prices based on their specific needs, while a forward capacity mandate creates a fixed set of costs that cannot be managed in the same way through behavior and real-time market participation. As a result, while the costs of an LSE obligation are difficult to calculate with any accuracy, TIEC is certain that adding a capacity requirement on top of the existing energy only market ***will*** increase customer costs, potentially substantially.

Retail Costs. Separate from the increase in wholesale costs, the Commission must consider the potential increase in retail costs that will result from decreased competition. Today, large "gen-tailer" REPs tend to charge a premium compared to other mass market, pure-play REPs. With retail competition reduced even further, this premium will increase and customers will be exposed not only to higher wholesale costs, but a higher retail mark-up on top of that. Again, at some point regulated rates with periodic Commission review would provide a better value for customers than an electricity cost that includes these capacity payments and retail premiums.

TIEC notes that customers are already being exposed to a variety of cost increases following Winter Storm Uri both from legislative and PUC action, as well as other external factors. Additional costs from an LSE obligation would be on top of: (a) rising gas prices, (b) increased ORDC revenues under the changes being contemplated, (c) increased ancillary service costs for the quantities in place today and the significant expected quantities of ECRS, and (d) general inflation and cost increases from supply chain issues and economic factors. While TIEC recognizes that natural gas prices under \$3/MMBtu have put pressure on solid fuel units and CCGTs, these low natural gas prices do not significantly impact the economics of ***peaking*** plants, which is what the market really needs. It is important to not overcompensate for low energy prices by swinging the pendulum too far in the other direction as a reactive measure.

14. How long will the LSE Obligation plan take to implement?

TIEC anticipates that writing all of the rules and requirements around an LSE obligation with meaningful stakeholder input would realistically take at least two years, and likely three or four. It took roughly two years to design and draft protocols around real-time co-optimization, which was a relatively uncontroversial upgrade to the existing market design. Once the rules have been implemented, the obligation would not actually take effect for three years in the future. As a result, TIEC does not expect an LSE obligation to have any impact on the market for at least five years, aside from commanding substantial legal and technical resources from the Commission and stakeholders. Due to the heavily administrative nature of an LSE obligation, TIEC also anticipates that it will be perpetually "under-construction" as market participants continuously jockey over rules and requirements that will favor their positions. Importantly, investment is often chilled when major market design changes are being considered due to the substantial regulatory uncertainty around the ultimate outcome. As a result, pursuing an LSE obligation may actually delay investment in dispatchable generation until it takes effect.

16. Are there relevant "lessons learned" from the implementation of an LSE Obligation in the SPP, CAL-ISO, MISO, and Australian markets that could be applied in ERCOT?

TIEC notes that these markets are very different from ERCOT. The US markets referenced in this question are almost entirely served by regulated, vertically integrated utilities. An LSE obligation is much more compatible with rate-regulated electric service than a competitive wholesale and retail market like that in ERCOT. Further, TIEC notes that these markets have also experience significant reliability issues due to extreme weather and intermittent generation variability, despite being largely regulated ***and*** having some form of a forward capacity mandate.

TIEC has limited information about the LSE obligation in the Australian market but understands it to be (a) relatively new, and (b) financial rather than physical, which is a significant difference.

Respectfully submitted,

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ATTORNEYS FOR TEXAS INDUSTRIAL ENERGY CONSUMERS

PUC DOCKET NO. 52373

REVIEW OF WHOLESALE	**§**	**PUBLIC UTILITY COMMISSION**
ELECTRIC MARKET DESIGN	**§**	**OF TEXAS**

TEXAS INDUSTRIAL ENERGY CONSUMERS' EXECUTIVE SUMMARY

1. ***The ORDC is currently a "blended curve" based on prior Commission action. Should the ORDC be separated into separate seasonal curves again? How would this change affect operational and financial outcomes?***

   - The ORDC should be separated into eight curves (two per season, for on-peak and off-peak) to provide more accurate valuations of reserve based on seasonal variability, which has become a primary reliability driver. This will better reflect actual reliability risks by season and improve performance incentives.

2. ***What modifications could be made to existing ancillary services to better reflect seasonal variability?***

   - Ancillary services should be procured based on actual seasonal variability data to better address intermittent output, forced outages, and other reliability risks. This is similar to ERCOT's current "conservative operations" but based on actual data.

3. ***Should ERCOT develop a discrete fuel-specific reliability product for winter? If so, please describe the attributes of such a product, including procurement and verification processes.***

   - ERCOT should develop a separate, competitively bid product where participating resources can participate in energy or ancillary services as they choose.

4. ***Are there alternatives to a load serving entity (LSE) Obligation that could be used to impose a firming requirement on all generation resources in ERCOT?***

   - TIEC sees two potential options: (1) procuring additional ancillary services based on seasonal variability and allocating them based on cost causation; or (2) dynamic "failure to firm" penalties, where the Commission assesses penalties for performance shortfalls under certain conditions for all resource types.

5. ***Are there alternatives to an LSE Obligation that could address the concerns raised about the stakeholder proposals submitted to the Commission?***

   - TIEC believes that providing additional revenues for dispatchable generation through new or expanded ancillary services that target seasonal variability is the most cost-effective solution to the actual reliability issues ERCOT faces.

6. ***How can an LSE Obligation be designed to protect against the abuse of market power in the wholesale and retail markets?***

   - TIEC is extremely concerned that attempting to address transparency and market power issues in an LSE obligation would ultimately translate into a central clearing model. This would be the worst outcome for customers, who would be forced to pay a clearing price for energy and capacity. A model that forces retail and generation consolidation and creates barriers to entry for pure-play REPs may not offer any real advantage over rate regulation.

- An LSE obligation will force large customers into an inflexible three-year forward procurement based on a static set of administrative assumptions. This will be very challenging for new large customers because they will not have certainty about their maximum demand or interruptibility three years in advance, and may have difficulty finding an LSE with sufficient "length" in its capacity position to cover a large load.

8. Can the reliability needs of the system be effectively determined with an LSE Obligation? How should objective standards around the value of the reliability-providing assets be set on an on-going basis?

- Administrative determinations of reliability needs and resource values are inherently flawed and inaccurate. Focusing on real-time market incentives is the best approach.

10. How will an LSE Obligation incent investment in existing and new dispatchable generation?

- An LSE obligation will not shift incentives to fund dispatchable generation because intermittent resources do not need additional revenue streams, and there is no realistic framework for an LSE obligation where intermittent resources receive zero value.

11. How will an LSE Obligation help ERCOT ensure operational reliability in the real-time market. (e.g., during cold weather events or periods of time with higher than expected electricity demand and/or lower than expected generation output of all types)?

- LSE obligations and other forward constructs do not meaningfully improve operational reliability. LSE obligations are based on static "snapshots" that are inherently administrative and inaccurate. Resources also predominantly on forward capacity payments rather than real-time revenues, diluting real-time performance incentives.

13. What is the estimated market and consumer cost impact if an LSE obligation is implemented in ERCOT? Describe the methodology used to reach the dollar amount.

- Although it is almost impossible to predict the cost of a vague, decentralized "paid-as-bid" LSE obligation, adding a capacity requirement on top of the existing energy only market will certainly increase wholesale and retail customer costs, potentially substantially.

14. How long will the LSE Obligation plan take to implement?

- TIEC does not expect an LSE obligation to have any impact on the market for at least five years in the future. It will also be perpetually "under-construction" as market participants jockey over rules and requirements that will favor their positions.

16. Are there relevant "lessons learned" from the implementation of an LSE Obligation in the SPP, CAL-ISO, MISO, and Australian markets that could be applied in ERCOT?

- The LSE Obligation functions very differently in these markets because (1) the US markets are served by regulated, vertically integrated utilities; and (2) the Australian market's LSE obligation is financial rather than physical, and also fairly new.